

Comments and recommendations for the Lawrence Livermore National Laboratory panel on “Groundwater Monitoring in Areas of Oil and Gas Exploration”, developed and presented by Dr. Steven White, Dept. of Biological Sciences, Duncan Hall Rm 240 (research lab), San Jose State University, San Jose, CA. (1-408-924-4843 or sjwhite@ email.sjsu.edu).

1. As revealed at the Workshop and in the 4th paragraph on page 8 of the discussion paper entitled “Oil, Gas, and Groundwater Quality in California—a discussion of issues relevant to monitoring the effects of well stimulation at regional scales”, by K. A. Taylor et al from the California Water Science Center and the U.S. Geological Survey (henceforth simply referred to as the “CWSC discussion paper”), the “chemical additives” used in “well stimulation” (hydraulic fracturing and/or acid fracturing) are “the same/same type of” additives used in “water-and steam-flooding enhanced recovery operations”. First off, since ***the exact nature of the chemical additives (and their concentrations) used at any specific well are currently unobtainable by the public*** (that information may or may not be revealed to DOGGR, but it is certainly not made available to the public), this is hardly a reassuring revelation. ***It is thus suggested that the Lawrence Livermore National Laboratory (LLNL) panel recommend to the State Water Resources Control Board that the chemical additives (and their concentrations) used at any specific well undergoing “well stimulation” be posted at the DOGGR website and be made available to the public.*** As was stated by a colleague (retired petroleum engineer James Maggard, with whom I collaborate on groundwater issues), “Without knowing what additives are present, water monitoring would be a complete waste of time. Furthermore, without having at least some idea of the concentrations present, you’d be forced to assay for everything at the parts per billion level, and testing to the PPB level for every chemical would be extremely expensive.” This practical suggestion is really only one asking for transparency of process and public access, and as such is a minimal request. It is extremely unsettling, however, to find that these same chemicals can be (and often are) used in “water-flooding”, “steam-flooding” and “cyclic steam” applications. If, in reality, these same dangerous chemicals are being injected in these “enhanced recovery operations”, ***it also seems logical to request that wells where water-flooding, steam-flooding or cyclic steam injection employ these chemicals also be posted at the DOGGR website, and the chemicals and their concentrations made available to the public.***
2. In paragraph 2 on page 25 of the CWSC discussion paper, the authors state that “Water injected for water and steam flooding generally contains additives”. In light of what was presented at the Workshop and in the CWSC discussion paper, it is clear that ***the public has been (and is continually being) misled by the terms “water-flooding” and “steam-flooding”***, since it strongly suggests that water (or steam) is the only reagent being used in the “well enhancement” operation. Every single person I’ve spoken to has

been very upset to learn that a “water-flooded” well (one that is currently outside the control of even SB4-based regulation) might easily be one that has been flooded with the same compounds found in hydraulic fracturing fluid. If your children were given “water” to drink and the water also contained cyanide and arsenic, is it just “water”? ***This blatant mislabeling of toxic material as “water”... inherent in such terms as “water-flooding” and “steam-flooding” and cyclic “steam” injection... is irresponsible at least, and does a huge disservice to the public. It is thus suggested that this practice be avoided entirely in any recommendations (either written or verbal) presented to the State Water Resources Control Board (SWRCB) by the LLNL.*** In place of “water” used in this context, I propose the term “injection fluid” (and “injection vapor” as opposed to “steam”).

3. As presented in the Workshop and in the first paragraph on page 10 of the CWSC discussion paper, it states that “flowback waters from individual well stimulation events are mixed into the overall produced water waste stream.” On the same page, it then shows in a figure and associated text that the produced water is commonly re-injected [typically via Class II injection wells] “for enhanced recovery”. Also as revealed at the Workshop, Class II injection wells are also used for disposal of “wastewater” (combined “flowback” and “produced” water). Both operations thus can work with water containing some or all of the same toxic chemicals utilized in hydraulic fracturing fluid. This revelation then begs an important question. How will the State be able to successfully monitor degradation of groundwater quality (due to leakage from Class II injection well sites) if they are concentrating only on potential leakage from oil/gas production wells? To deal with this complication, ***it is thus suggested that any monitoring well program recommended by the LLNL panel include monitoring of all oil and gas field-associated Class II injection wells in addition to all oil and gas production wells.***
4. Given that “produced water” is often mixed with “flowback water”, the resulting “wastewater” contains hydraulic fracturing fluid components and thus, by definition, toxic material. Since it is current practice to inject that “wastewater” back underground (either for use in “enhanced recovery” or simply to dispose of it), it becomes important to know just what components (and approximately how much of each) are being injected underground. Unless some type of reasonably accurate accounting of waste components is kept, regulators will have little idea of exactly what chemicals are present in the waste stream, nor the approximate load (mass) of any waste stream component. ***It is thus suggested that some type of chemical component mass accounting system be recommended by LLNL.*** A number of methods by which this goal might be met present themselves immediately. The first is to rely on the well operators to accurately record the nature of the hydraulic fracturing fluid(s) used and the volume(s) used at the well, then assume that recovery of all hydraulic fracturing fluid components in the “flowback” water

was complete (100% recovery). Whatever fraction of that “flowback water” (either undiluted or diluted with “produced water”) was later employed in subsequent well injection (whether for “enhanced recovery” or “final disposal”) could then be used to provide a crude estimate of how much of each component was present in that waste stream. For example, if 50% of the “flowback water” was ultimately disposed of by underground injection, then it would be assumed that all components originally present in the hydraulic fracturing fluid were present at 50% of their original concentrations in that waste stream. That approach suffers, however, from the likelihood that the assumption of 100% recovery will probably not be valid. It might still be informative and useful, however, to actually chemically analyze the “flowback water” at a number of wells (ideally from different locations and thus different geologic formations) to obtain more accurate estimates of the range of recovery efficiencies actually encountered. From this, one could derive a less subjective “average recovery efficiency”. One might then apply that (hopefully more accurate) average recovery efficiency to modify the approach outlined above and (hopefully) obtain a more accurate estimate of the components and loads present in the waste stream. Both approaches above, however, still suffer from a second erroneous assumption... that the only chemicals that could be present in the flowback water are those originally present in the hydraulic fracturing fluid itself. Unfortunately, this is not the case since “the flowback water is usually contaminated with leached metals and formation hydrocarbons that were not originally present in the fracking fluid” (J. Maggard). The third approach, of course, is to simply chemically analyze a sample of each waste load just prior disposal (or use in “enhanced recovery”) to obtain a much more accurate estimate of the components and amounts present in the waste stream. While the second approach is preferred due to its inherently better accuracy, it will also undoubtedly prove more expensive. ***Whatever approach is chosen, some type of chemical component mass accounting system should be recommended by LLNL.***

5. Ideally all this “wastewater” referred to above would be sent to some type of “recycling/water purification” facility so that water could be reclaimed in a usable (hopefully to greywater standards or better) form and the toxins concentrated to allow efficient recovery and/or destruction or long-term sequestration. The use of such “recycling/water purification” facilities would greatly decrease the risk of contamination to our groundwater sources, and thus the risk of permanent aquifer degradation. This approach would also provide supplementary jobs both due to new facilities construction and facilities operation, and the use of these facilities also not need be limited to decontaminating wastewater streams solely from the oil and gas industries. ***It is thus suggested that LLNL recommend that any contaminated water (whether “flowback” water, “produced” water or mixed “wastewater”) containing constituents found in hydraulic fracturing fluid be sent to and***

processed by a water recycling/purification plant designed (or retrofit) to remove any hydraulic fracturing fluid components present.

6. As repeated numerous times in the Workshop and in the second paragraph of page 12 of the CWSC discussion paper, the participants/authors acknowledge that “Older wells are more likely to be [contamination] pathways, because they were constructed before current well-integrity regulations, wells deteriorate over time, and because they have had more exposure to stresses from land deformation and subsidence.” ***Given the common occurrence of old, inactive and/or abandoned oil and gas wells near to active wells or proposed well sites, it is suggested that the LLNL recommend to CSWRCB that it commit to mapping all these older “inactive” and “abandoned” wells and collecting baseline water quality data around these wells, since these are more likely to be the conduits of contamination.*** “This should be done immediately, since contamination is likely occurring in some of these very old inactive and abandoned wells today. Also, if a field is still active it will have the income required to repair or properly plug and abandon the older wells. If the field is no longer in production and they wait until land has been sold, it’s likely the US taxpayer will be stuck with the bills. Finally, abandoned water wells may also be a problem (and so should be mapped and integrity checked), since hydraulic fracturing fluid, flowback water and/or produced water, if stored in unlined ponds or leaking storage tanks, may seep into a shallow aquifer (contaminating it) and then secondarily flow into deeper aquifers through the abandoned water well.” [J. Maggard]
7. The last paragraph on page 13 of the CWSC discussion paper states that “an assessment of groundwater vulnerability for the regional monitoring program could be based on proximity of the useable water to oil and gas deposits”, since “the thickness of the layer of separation is inversely proportional to the vulnerability of the groundwater to contamination”. ***While thickness of the intervening rock layer is clearly important, no stated consideration is given to the NATURE of the intervening rock strata (the number and type of soil/rock formations)... just the thickness.*** The authors go on to state that “additional factors such as number of abandoned oil and gas wells, number of active oil and gas wells, a history of waste injection, history of well stimulation, surface waste disposal or spills or significant faulting, may also increase the probability of groundwater contamination.” All these considerations indeed seem both true and important, but they are not a comprehensive list. ***While the NUMBER of abandoned oil and gas wells is important, for example, so also is the WELL DEPTH, the well CASING STATUS and the geology/hydrogeology surrounding each well. It is thus suggested that LLNL also consider these variables when assessing the vulnerability of any water source.***

8. As presented in the 3rd paragraph on page 26 of the CWSC discussion paper and in the Workshop by one of the authors of that paper, one approach to predicting a “pathway” for pollutant transport is by “using hydraulic gradients to determine if there is any reasonable chance of constituents [pollutants] moving from areas affected by oil and gas development towards potentially useable groundwater sources.” This approach of using existing hydraulic gradients to predict the direction and rate of water and dissolved solute flow is quite logical and has a long history of use. Subsequently, the authors then state, “If there is no flow towards these [groundwater] sources, then further study of how the gradient might be managed to prevent transport would not be needed.” ***The worry here is that it appears the authors believe all hydraulic gradients are infinitely stable and never change. California is in a period of unprecedented groundwater overutilization (overdrafting) and depletion. It has also been subject to large scale subsidence (as reported in numerous papers in the journal Science), and is unarguably the subject of commonly occurring seismic activity... all of which can potentially affect hydraulic pressure gradients in groundwater. As groundwater table levels change, as groundwater reservoirs are depleted (or recharged, if we are so lucky) and hydrostatic pressure levels change, it seems logical that the direction and/or rate of water flow (and thus the direction and magnitude of pollutant transport) could change with it. Taking one static measurement of a hydraulic gradient may thus not provide sufficient information to protect groundwater sources in the long term. It is thus suggested that LLNL recommend to the CSWRCB that hydraulic gradients be reassessed periodically to better ensure accurate predictions of pollutant flow.***
9. As presented at the Workshop and on page 29 of the CWSC discussion paper the authors show a table of “constituents” [chemicals that may appear in injection fluids, dissolved gasses and ions that might appear in formation water, naturally occurring radioactive materials that might be encountered during drilling etc] that does indeed seem to represent a logical constellation of analytes to assay for in any groundwater monitoring program, especially one associated with oil and gas development efforts. What is very troublesome, however, is that the authors state that this monitoring “should be considered for the REGIONAL monitoring program.” ***Indeed, such constituents should be assayed for, but such assays should NOT be limited to the REGIONAL monitoring program. Without exception, the entire list of “constituents” specified in the Table should also be assayed for by EACH well operator at EACH groundwater monitoring well. It is suggested that this recommendation also be included by LLNL.***
10. The complexity of the chemical mixture that represents a typical hydraulic fracturing fluid was touched upon (albeit briefly) at the Workshop. More specifically, on page 30 of the CWSC discussion paper the authors include, amongst the list of constituents to be assayed for, “Chemical constituents that

are representative of the well stimulation treatment fluid composition.” ***This is a CRITICALLY IMPORTANT point that cannot be overemphasized. The list of chemicals (posted by the EPA) that can appear in hydraulic fracturing fluid number over a thousand. Since hydraulic fracturing fluids are in fact a complex mixture of constituents, often custom made at each well site to deal with the unique conditions encountered in that particular well (conditions specific to a particular rock formation, at particular pressure and temperature conditions etc), how will the “representative” constituents to assay for be selected? By abundance, and thus likelihood of detection? By toxicological impact factor? If the latter, using what organism(s) as the toxicological target(s)? By environmental half-life? What analytical instrumentation and methodologies will be employed (this is important, since this will help determine limits of sensitivity for any particular analyte). It is strongly suggested that these critical considerations be included in developing the LLNL recommendations, and that the rationale for the decisions be included in the recommendation report so that they can be clearly explained to the public.***

11. The issue of selecting the frequency of groundwater testing was mentioned at the Workshop, but not really discussed. This is another important question. One useful way to approach this problem is to attempt to first define the minimum sampling (monitoring) frequency as that minimum time necessary for transport of a pollutant from the point source (a production well, for example) to the nearest monitoring well. ***What is needed then is the “minimum transport time” from the production well to the monitoring well.*** Since equilibrium binding constants (and “association” and “dissociation” rate constants) for most components in the pollutant (analyte) mix to the wide variety of soil/rock adsorption surfaces along a diffusion pathway are not really known, it seems reasonable to simplify the approach by trying to determine the flow rate of the groundwater between the pollutant source and the monitoring well. ***Measuring the hydraulic gradient occurring between the production well and the monitoring well, and calculating (or directly measuring) the average flow rate of the groundwater moving across that minimum distance, will thus provide at least a crude approximation of the transport time.*** Since ideally we would want to detect a well leak as soon as possible, this also represents the minimum frequency of groundwater testing. If, for example, the hydraulic gradient indicated a minimum transport time of 30 days, release of any analyte from the production well on January 1st would probably not be detectable until 30 days later (January 30th). If you normally measure on the last day of the month, you will still detect the leak on January 31st, only one day later than optimally possible. Logically, while it is clear that under many instances you might not detect any particular release event for almost two times that minimum duration (if the analyte was released on January 5th, for example, it would not be detected until the February 31st sampling date), this

still represents a reasonable solution to the problem. ***It is thus suggested that LLNL recommend this “minimum transit time” approach to set the groundwater testing frequency.***

12. The issue of the duration of the groundwater monitoring program was also mentioned at the Workshop, but it too was not really discussed. On page 32 of the CWSC discussion paper, however, the authors state “The duration of monitoring should extend beyond the end of the oil and gas activities”. This is absolutely true. The question remains, however, ***for HOW LONG should groundwater monitoring at each site be continued? Hydrocarbons can be exceedingly stable (they have, after all, existed underground for many millions of years). In general, very stable (long-lived) analytes that pose health hazard/toxicity treats should have very long monitoring periods. Given that what is potentially at stake here is the safety of our aquifers... our very drinking water... what monitoring duration period do you propose? Fifty years? One hundred years? Two hundred? What rationale will you provide for your recommendation? Given that groundwater quality must be protected not simply for the next decade, but for multiple generations into the future, it is suggested that a very long groundwater monitoring period be recommended by LLNL... 50-75 years at least (preferably on the order of two to three human generations).***
13. Almost completely avoided at the Workshop ***was the problem of obtaining high quality toxicological data on the over one thousand chemicals listed as components in various hydraulic fracturing fluids formulations.*** This avoidance is entirely understandable, however, given the relative lack of such critical data. Unfortunately, in reality such data will NEVER be generated unless gathering it is mandated by law. Since it is the oil and gas industry that is injecting these chemicals into production wells, injection wells and chemical disposal sites (and potentially threatening groundwater quality as a result), and since it is the oil and gas industries that profit from this activity, it seems reasonable to require the oil and gas industries to pay for the generation of such critically important toxicological data. ***It is therefore suggested that LLNL recommend that the oil and gas industry as a group (and/or well operators as individuals) be REQUIRED to pay fees to be applied specifically to toxicological testing of the chemicals used in hydraulic fracturing fluids (and that the resulting information be incorporated into a publically accessible database of some kind), and as an obligatory part of any license to inject (or otherwise introduce) chemicals down into a well.***
14. Probably one of the thorniest problems discussed at the Workshop involved determining how many monitoring wells are necessary, both within an “aggregated area”, an “oil field”, and a “region”. A few solution options are presented. **OPTION #1:** One might begin to address this problem by considering another massive monitoring problem... point sources of air

pollution... one example of which is the ubiquitous automobile. The State wants to know which automobiles, if any, are actually polluting. Now it could simply monitor a small but “statistically significant” sampling of all automobiles in California, but that would only identify a small number of polluting autos and do little more than yield an estimate of the fraction polluting... it would not prevent pollution from any of the untested automobiles, nor would it identify, specifically, which of those cars are polluting and to what extent they are polluting. Since the latter information is of critical importance to prevent (or at least minimize) further air quality degradation, the State has opted for monitoring each and every automobile (each and every potential pollution point source) in California, even though a huge fraction (if fact, the vast majority) of automobiles pass the smog test. If we consider each and every oil and gas well as a potential point source of pollution, we can easily envision a similar monitoring solution imposed upon the oil and gas industry by the State. The cost of drilling that many monitoring wells, however... potentially upwards of 100,000... is probably prohibitive even to the ultra-rich oil and gas industry (and would certainly be unaffordable by the State). Even if you cut the number of wells required by this model in half... or even a quarter... the cost would probably be unbearable. Even a tenth of the total well number may be too huge an expense to bear. And that is the point. An efficient monitoring system designed to quickly identify any and all polluting wells across the state will require the creation of more monitoring wells and the expenditure of more money than the oil companies (and/or the State) could afford. Thus, while I didn’t feel like explaining it when I asked the last question at the meeting, it was this thinking that drove me to ask, “Is poisoning large volumes of our precious water and removing it forever from the earth’s hydrologic cycle by injecting it deep underground (so that such water will never again contact any aquifer or surface water), really the best use of this resource?” Is it sustainable? Indeed, is it even an appropriate use? If the answer is “No”, then it seems incumbent upon the LLNL to recommend to the State Water Resource Control Board that an effectively protective groundwater monitoring system simply can not be affordably constructed, and thus to recommend that hydraulic fracturing and fracturing fluid use (including the use of similar “chemical additives” in other applications like “water-flooding”, “steam-flooding” and “cyclic steam injection”) be prohibited in the State of California. If adopted, this recommendation would immediately remove the threat to groundwater posed by the thousand or more chemicals currently allowed for use in various formulations of hydraulic fracturing fluid, as it would for the threat posed by the “chemical additives” allowable in “water-flooding”, “steam-flooding” and “cyclic steam injection”. As such it would also immediately remove the need for the huge, prohibitively costly groundwater monitoring system that would likely be required to safeguard our aquifers and, as a bonus, save the California taxpayers a literal mountain of money. There would still be a contamination risk, of course, from hydrocarbons (either from the formation or from a breach in the well casing or via surface

spills), naturally occurring radioactive materials etc, but with the removal of all the chemicals present in fracking fluid (and the “chemical additives” often used in “water flooding”, “steam flooding” and “cyclic steam injection”) the risks to the aquifers would be greatly reduced, along with the size and scope of any groundwater monitoring system still thought necessary. Additionally, it would also prevent the poisoning and permanent loss of tens (if not hundreds) of millions of gallons of drinking water and the unnecessary subsidence coincident with withdrawal of groundwater for “well stimulation” and “enhanced recovery” use. Does the oil and gas industry have an option under these circumstances? Of course they do. They need to develop a way to extract oil and gas without employing methods that introduce toxic chemicals underground that can potentially threaten our ground and surface water resources. **OPTION #2:** Recommend a monitoring system 10 to 30 fold smaller in monitoring well number (relative to the total number of active, inactive and abandoned wells present, bringing the ratio to one monitoring well for every 10 to 30 active/inactive/abandoned wells). As a modification to this plan, all wells in the state might first be inspected for well integrity. If the well casing and concrete adhesion to the formation were tested periodically it would eliminate some risk and allow monitoring staff to focus on those wells that did not pass inspection. Additionally, this may help in identifying wells or “well aggregates” or “fields” that require more (or less) in the way of monitoring wells. This option will certainly require insightful placement of each monitoring well (especially at the 1:30 ratio), which in turn would require extensive hydraulic gradient mapping and vulnerability assessment... making it highly unlikely that the system would actually be built and put in place in the near future (when the oil and gas industry expects to resume large scale hydraulic fracturing and drilling). The cost of the option, however, would still likely meet huge resistance from the oil and gas industry (who, presumably, would be expected to bear most of the costs of its construction). Moreover, at a ratio of one monitoring well to at least 30 potential point sources of pollution (remember that you will also need to monitor for surface spills, leakage from sumps and tanks etc that may be removed some considerable distance from the wellheads), I believe we’d be forced to accept the very real possibility that the system will probably not catch all polluting wells, sumps/ponds, storage tanks, pipelines, surface spills etc in a timely manner... if it could even detect every leaking source at all. In the end, I believe with this option we could only hope that an aquifer is not significantly contaminated during your lifetime. **OPTION #3:** Create a monitoring system of only a few hundred to a thousand or so monitoring wells. At this low ratio of monitoring wells to potential pollution point sources (in the range of 1:100 at best), it seems highly likely that many breaches (even major ones) would go undetected... the sheer area and volume of earth to be monitored is simply too great for each monitoring well. Yes, this option is much better than nothing, but I believe it provides only a false sense of security. And if a major aquifer is contaminated, it will become

a nightmare. Cleaning up a poisoned aquifer is generally considered to be a prohibitively expensive... and ultimately impossible... proposition.